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Subject: Assessment of Feasibility of Closed-Cycle Wet Cooling and Impact of Desalination at Huntington Beach Generating Station

Dear Todd:

As you requested I have prepared this assessment of the feasibility of closed-cycle wet cooling, and the impact of a proposed desalination plant on wet cooling feasibility, at Huntington Beach Generating Station.

Please call me at (619) 295-2072 or e-mail at bpowers@powersengineering.com if you have any questions about this closed-cycle cooling assessment.

Best regards,

Bill Powers, P.E.

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Assessment of Impact of Desalination Plant and Feasibility of Closed-Cycle Wet Cooling Retrofit at Huntington Beach Generating Station

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July 29, 2006

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1. Executive Summary

Closed-cycle wet cooling is technically and economically feasible at the Huntington Beach Generating Station (HBGS). The estimated installed cost of two plume-abated wet towers would be approximately $40 million per unit or $80 million. Overall dimensions are 60 feet by 648 feet. The total cost impact of a closed-cycle cooling retrofit, at $4.4 million per year per unit, would be approximately 3 percent of gross revenue assuming an annual capacity factor of 50 percent. There appears to be adequate space for these two towers whether or not a 50 million gallon per day (Mgd) desalination plant is constructed at the same site. However, adequate space would have to be set aside for the cooling towers and associated circulating water piping during the design stage of the desalination plant to avoid adding unnecessary complexity and expense the wet tower retrofit.

The plantwide make-up water demand of the closed-cycle cooling water system would be a maximum of 12 Mgd if reclaimed water is used as the cooling medium. This represents a 98 reduction relative to once-through cooling (OTC). A second option if insufficient reclaimed water is available is to use seawater as the cooling medium in the wet towers. Significantly more seawater is necessary to achieve the same cooling tower performance attainable with freshwater due to the lower thermal efficiency of seawater as a cooling medium. A maximum of approximately 20 to 25 Mgd of seawater would be evaporated in the wet towers or discharged as blowdown. This represents a 96 percent reduction in water use relative to OTC.

Units 3&4 were upgraded in 2003. HBSG is unique along the coast in that the owner simply upgraded existing OTC steam boiler unit instead of replacing the unit with a combined-cycle plant. The cost of this retooling project was $130 million.
It is unlikely that AES or any future owner would voluntarily convert the cooling system to closed-cycle prior to a mandated OTC phase-out date without: 1) a regulatory requirement such as 316(b) requiring such as action, 2) a lawsuit forcing such a conversion, or 3) replacement with a combined-cycle gas turbine plant for economic reasons.

However, HBSG will not be able to compete on an efficiency basis with the new combined-cycle plants that are gradually replacing aging coastal boiler plants. Therefore it is quite possible that AES is weighing the near- to mid-term replacement of HBSG Units 1&2 and potentially Units 3&4 as well to combined-cycle. The cost of replacing the existing boilers with the same capacity, 860 MW, of combined-cycle plant would be $400 to $500 million. The cost of the Units 3&4 retooling project of $130 million is significant but not so significant that it would necessarily impede AES from moving forward with a combined-cycle replacement project.

The principal problem posed by the proposed desalination plant is that it would occupy the only land on the HBGS site that is large enough for a replacement combined-cycle plant. There would not be space at the site to build a combined-cycle replacement project of similar capacity without demolishing the existing plant if the proposed desalination plant is built.

An additional impediment to a closed-cycle retrofit is the high degree of economic dependence of the proposed desalination process on the existing OTC system. The warm OTC discharge water improves the efficiency of the desalination process, thereby lowering the cost of desalinated water production. More importantly, the desalination plant, by "piggy-backing" atop an existing NPDES permit holder with all the OTC already infrastructure in place, eliminates the both the construction expense of this infrastructure, estimated at $150 million for a 50 Mgd desalination plant, and the need to apply for a separate NPDES permit. The economic dependence of the desalination process on the existing OTC system would almost certainly lead to the desalination plant owner and the principal purchasers of desalinated water becoming strident opponents of any attempt to convert the HBGS to closed-cycle cooling.

2. Proposed Desalination Project and Relation to Existing OTC System at HBGS

2. 1 Existing OTC System

The existing once-through cooling (OTC) system at the HBGS draws cooling water from the ocean to condense steam in the boiler steam cycle. Thc cooling water absorbs heat from the low pressure steam exiting the steam turbine in a heat exchanger known as a "surface condenser," causing this steam to condense to water. This condensed water, known as "boiler feedwater," is then recirculated through the boiler. The HBGS OTC system is permitted to circulate up to 514 Mgd of seawater. The historical maximum OTC flowrate is 507 Mgd.[1]

The current National Pollution Discharge Elimination System (NPDES) permit allows a maximum of a 30 °F rise in OTC return (discharge) water temperature at HBGS.[2] According to the NPDES monitoring reports for 1996-2000, the differcnces in discharge temperature and that of the intake waters ranged from 8.4 °F to 24.7 °F. During the 1996-2000 period, only Units 1&2 were operational.

2. 2 Proposed Desalination Plant

The proposed 50 Mgd seawater desalination project at HBGS would convert a portion of the OTC seawater discharge into drinking water using a reverse osmosis (RO) desalination process. Supply water for the desalination process would be drawn from the existing OTC discharge pipe. The desalination plant would draw approximately 100 Mgd from the discharge pipe and produce 50 Mgd of potable drinking water. The remaining 50 Mgd would be seawater with an elevated salt concentration, as the salts in the 50 Mgd of potable water would be concentrated in this 50 Mgd discharge stream. The 50 Mgd of concentrated discharge from the RO process would be blended with the OTC discharge flow for dilution prior to ocean discharge.

The proposed desalination project would consist of a seawater intake system, pretreatment facilities, a seawater desalination facility utilizing reverse osmosis technology, post-treatment facilities, product water storage, on- and off-site landscaping, chemical storage, on- and off-site booster pump stations, and 42- to 48-inch diameter product water transmission pipelines up to 10 miles in length.[3] **Figure 1** shows the

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[1] City of Huntington Beach, *Draft Environmental Impact Report –Desalination Project at Huntington Beach*, April 5, 2005, p. 3-1.
[2] California Energy Commission, *Final Staff Assessment – HBGS Unit 3&4 Retooling Project*, March 2001, p. 262.
[3] City of Huntington Beach, *Draft Environmental Impact Report –Desalination Project at Huntington Beach*, April 5, 2005, p. 3-2.

location of the structures and parcels proposed for the 50 Mgd desalination plant at HBGS. The location of the desalination plant piping interconnections with the existing OTC discharge piping is shown in **Figure 2**.

The RO process would be a single-pass design using high rejection seawater membranes. The system would be made up of 13 process trains (12 operational and one standby). Each RO train would have a capacity of approximately 4 Mgd. High pressure electric feed pumps would convey water from the intake filters to the RO membranes. The pumps will provide feed pressures of 800 to 1,000 pounds per square inch. The actual feed water pressure depends on several factors including the temperature of the intake water, salinity of the intake water, and the age of the membranes. Additional energy savings may result from the use of warmer water supplied from the HBGS OTC discharge. The desalination process will be designed to operate at both ambient and elevated seawater temperature. However, using warmer water increases the efficiency of the RO membranes.[4]

The 50 Mgd desalination plant would require approximately 30 to 35 MW of power on a continuous basis. The daily energy consumption of the proposed plant is estimated at 720 to 840 MW-hr per day based on 24 hours per day operation.[5]

2. 3 Economic Dependence of Desalination Plant on Existing OTC System

A major obstacle to the conversion of HBGS to closed-cycle cooling is the high degree of economic dependence of the proposed desalination process on the existing OTC system. The warm OTC discharge water improves the efficiency of the desalination process, thereby lowering the cost of desalinated water production. More importantly, the desalination plant, by "piggy-backing" atop an existing NPDES permit holder with all the OTC infrastructure already in place, eliminates both the construction expense of this infrastructure, estimated at $150 million for a 50 Mgd desalination plant, and the need to apply for a separate NPDES permit.[6] The economic dependence of the desalination process on the existing OTC system would almost certainly lead to the desalination plant owner and the principal purchasers of desalinated water becoming strident opponents of any attempt to convert the HBGS to closed-cycle cooling.

[4] Ibid, p. 3-25.
[5] Ibid, p. 3-27.
[6] M. Burge, *Power Plans Could Change Desalination*, San Diego Union Tribune, July 23, 2006.

3. Assessment of Closed-Cycle Cooling at HBGS

3. 1 Cooling Capacity Required

HBGS is rated at 860 MW and consists of two natural gas-fired utility boiler combinations, Units 1&2 and Units 3&4, each rated at 430 MW. The estimated rated heat input for HBGS Units 1&2 and 3&4, assuming a 10,000 Btu/kWh (HHV) design heat rate, is:

Units 1&2, 430 MW: 4,300 MMBtu/hr
Units 3&4, 430 MW: 4,300 MMBtu/hr

The EPA indicates approximately 44 percent of the heat input to a fossil fuel steam plant is removed by the condenser cooling system.[7] Therefore the maximum cooling system heat rejection required for Units 1&2 and 3&4 is:

Units 1&2: 4,300 MMBtu/hr × 0.44 = 1,900 MMBtu/hr
Units 3&4: 4,300 MMBtu/hr × 0.44 = 1,900 MMBtu/hr

3.2 Plume-Abated Wet Tower Closed-Cycle Option

There are two closed-cycle cooling options available: 1) wet cooling towers and 2) air-cooled condensers (ACC). Wet cooling towers are more compact than ACCs, requiring approximately one-third the footprint for the same cooling capacity. ACCs also are slightly less efficient cooling systems than wet towers on hot days. Existing coastal boiler plants are equipped with steam turbines designed for low to moderate backpressure, up to 5.0 or 5.5 inches of mercury. Steam turbines in air-cooled plants are generally designed to withstand higher backpressure, typically up to 8 inches of mercury or higher, to account for the ACC's less efficient performance on hot days. As a result, retrofitting the HBGS to air-cooling would require modifications to the steam turbines in each generating unit in addition to the cooling system retrofit. This is not the case for a wet tower retrofit, as the backpressure achieved with an appropriately sized wet tower approximates the backpressure profile of the OTC system. There have been numerous retrofits from OTC to wet towers in the U.S, several of which are discussed in detail in Section 3.6. There have been no retrofits from OTC to air-cooling. For these reasons an air-cooling retrofit at HBGS will not be considered further in this analysis.

It is important to note that air-cooling is a viable and often superior cooling option for combined-cycle gas turbine replacement projects. This is underscored by the voluntary selection of air cooling for two replacement projects recently announced for the

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[7] U.S. EPA, *Technical Development Document (TDD) for the Proposed Section 316(b) Phase II Existing Facilities Rule*, April 2002, p. 5-7.

California coast, the South Bay and Encina Power Plant replacement projects in San Diego County. There is very little difference in the cost of a new combined-cycle plant whether it incorporates OTC, closed-cycle wet cooling, or dry cooling.[8]

Use of a plume-abated tower, also known as a hybrid tower, greatly minimizes the aesthetic issues related to the vapor plumes associated with conventional wet towers under certain atmospheric conditions. It is now standard practice to specify plume-abated cooling towers for urban California sites such as HBGS. Use of plume-abated cooling towers at HBGS is assumed in this analysis.

3.3 Discussion of Plume-Abated Wet Tower Design, Cost, and Location Relative to Proposed Desalination Plant

The estimated installed cost of a plume-abated wet tower retrofit would be $40 million per unit or $80 million for the HBGS plant. This estimate assumes a 12-cell SPX Cooling Technologies plume-abated wet tower, Model F4910-5.3-12.[9] Each cell is 60 feet wide by 54 feet long by approximately 50 feet high. Overall dimensions are 60 feet by 648 feet. The design circulating water flowrate is 190,000 gallons per minute (gpm). The equipment cost estimated by SPX for the cooling tower alone is $16,000,000. The cooling tower equipment cost represents about 40 percent of the total retrofit cost for a plume-abated tower based on a recent (2005) Powers Engineering retrofit wet tower cost estimate for the 500 MW Danskammer power plant in New York. The Danskammer wet tower retrofit cost estimate is included as **Attachment A**. The overall installed cost per unit is therefore approximately $40 million.

The size of the wet tower is determined by the amount of heat that must be removed and the desired maximum steam condensation temperature at the steam turbine outlet. A primary measure of cooling tower performance is the "approach temperature." Approach temperature indicates how close the circulating water temperature "approaches" the ambient air wet bulb temperature at design conditions. Typical cooling tower approach temperatures range from 8 to 15 °F, with western U.S. sites tending toward the higher end of this range.[10] The design approach temperature specified by Powers Engineering for the HBGS wet towers is 12 °F. A 12 °F approach temperature at HBGS represents a good balance between cooling tower capital cost and performance. The design wet bulb temperature for the HBGS site is 69 °F based on available weather data.[11] This means that at full load operation (430 MW) when the ambient wet bulb temperature is 69 °F, the temperature of the "cold" cooling water exiting the cooling tower will be 81 °F.

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[8] John Maulbetsch presentation on cost of cooling technologies to the State Water Resources Control Board on behalf of California Energy Commission, December 7, 2005.

[9] J. Padilla, SPX Cooling Technologies e-mail specification and cost for HBGS wet tower, July 7, 2006.

[10] J. Maulbetsch, *Comparison of Alternate Cooling Technologies for California Power Plants - Economic, Environmental, and Other Tradeoffs*, prepared for Electric Power Research Institute/California Energy Commission, February 2002, p. 2-8.

[11] The wet bulb temperature is at or above 69 °F for 1 percent of the summertime hours. Reference: *Weather Data Handbook*, Ecodyne, 1980, p. 6-6, Laguna Beach dataset.

The plantwide make-up water demand of the cooling water system would be a maximum of 12 million gallon per day (Mgd) if reclaimed water is used as the cooling medium. This represents a 98 reduction in water use relative to OTC. This water demand consists of evaporative losses in the cooling tower (approximately 1.5 to 1.7 percent of total flow), and blowdown discharge from the tower to prevent too high a concentration of solids in the cooling water (approximately 0.3 to 0.5 percent of total flow).

The HBGS is located in Orange County. The Orange County Water District (OCWD) produces reclaimed water as a part of its Groundwater Replenishment System Project, and will increase reclaimed water production from 10 Mgd to 70 Mgd in 2007.[12] The reclaimed water is produced in Fountain Valley, approximately 5 miles from the HBGS. This water is currently slated to be used for groundwater replenishment, and it is unclear if any of this water would be available for use as cooling water at HBGS.

The two Orange County Sanitation District wastewater treatment plants are in Fountain Valley (Plant No. 1) and Huntington Beach (Plant No. 2). These plants discharge 230 Mgd of advanced primary and secondary treated wastewater through ocean outfall piping that passes within approximately 2 miles of the HBGS.[13] Although hundreds of millions of dollars are being invested in these two plants to upgrade their treatment capabilities,[14] there are no current plans to produce reclaimed water at either facility for purposes other than groundwater replenishment.

An available source of reclaimed water of adequate quality for HBGS cooling tower use is the Long Beach Water Reclamation Plant (LBWRP), located approximately 12 miles from HBGS. The LBWRP is located within one-half mile of the Orange County line. This plant produces approximately 25 Mgd of tertiary-treated reclaimed water.[15] Approximately 5 Mgd is used by local customers and the remaining 20 Mgd is discharged via Coyote Creek (cement-lined) and the San Gabriel River to the ocean via the San Gabriel Estuary. The mean 2005 sale price of reclaimed water produced by the LBWRP was $420/acre-foot, or approximately $1.30/1,000 gallons. Assuming the HBGS operates at an annual capacity factor of 50 percent, the cost of cooling water would be approximately $1.4 million per year per unit.

Transporting the reclaimed water from the LBWRP to the HBGS would also require 12 miles of 24-inch reclaimed water pipe.[16] The approximate installed cost this 24-inch pipe

[12] Phone conversation between B. Powers and OCSD engineer Jim Burror, July 25, 2006.
[13] Phone conversation between B. Powers and OCSD engineer Jim Burror,, July 27, 2006.
[14] Department of Justice press release, *Justice Department, EPA, Santa Ana Regional Water Quality Control Board Announce $600 Million Agreement*, November 15, 2004.
[15] 2005 Annual Report - Los Angeles County Sanitation District, Long Beach Water Reclamation Plant, pp. 21-25. Relevant pages from the 2005 Annual Report are included as **Attachment B** to this report.
[16] Water velocity in the 24-inch pipe at maximum flow of 8,000 gpm would be 5.7 feet per second. A 24-inch pipe is a conservative pipe diameter for this flow. Reference: U.S. EPA, *Technical Development Document for the Proposed Section 316(b) Phase I Existing Facilities Rule*, November 2001, p. 3-27.

is $200 per linear foot.[17] The total installed cost of the 12-mile, 24-inch pipeline would be approximately $13 million. The annualized capital recovery cost of this pipeline would be $1.2 million per year, assuming a 20-year capital recovery period at 7 percent interest.

A second option is to use a greatly reduced volume of seawater as the cooling medium in the wet towers. Significantly more seawater is necessary to achieve the same cooling tower performance attainable with freshwater due to the lower thermal efficiency of seawater as a cooling medium.[18] A maximum of approximately 20 to 25 Mgd of seawater would be evaporated in the wet towers or discharged as blowdown. This represents a 96 percent reduction in water use relative to OTC. The existing seawater intake could continue to be utilized as the source of make-up water. Beach wells might also be an alternative to eliminate any marine impacts caused by the 20 to 25 Mgd seawater demand of the cooling towers.

There is ample space to locate the cooling towers in the decommissioned HBSG fuel oil storage area in the case where no desalination plant is built in the same area. There also does appear to be minimally sufficient space to locate the two wet towers in the decommissioned fuel oil storage area if the proposed desalination plant is constructed. A possible location for two 12-cell cooling towers adjacent to the desalination structures is provided in **Figure 3**. The design and location of these facilities would have to be coordinated in advance of either the cooling towers or the desalination plant entering construction to effectively address the design challenges posed by the tight spacing. If the design is not coordinated in advance and the desalination project moves forward first, the cost of the cooling tower retrofit could be much higher than necessary. The higher cost would be driven by the need to physically relocate elements of the desalination plant to accommodate the cooling towers.

The existing circulating water system components are quite accessible at HBSG, facilitating the incorporation of this equipment in the wet tower retrofit. One potential approach to converting the existing circulating water system from OTC to closed-cycle to allow maximum reuse of existing equipment is shown in **Figure** 4. A completely new circulating water system can also be constructed with the wet towers if necessary. The $40 million retrofit cost estimate per unit includes sufficient budget for new circulating water pumps, pump bay, and circulating water piping. The cost estimates does not assume that any of the existing circulating water system is reused.

EPA has looked at several retrofits from OTC to wet towers and found that in most cases no surface condenser upgrade was necessary. The surface condenser is the point in the power plant where the cooling water absorbs heat. The function of the surface condenser is to condense low pressure, low temperature steam exiting the steam turbine. The steam

[17] U.S. EPA, *1999 Drinking Water Infrastructure Needs Study - Modeling the Cost of Infrastructure*, EPA 816-R-01-005, February 2001, p. Appendix A-12.
[18] Dr. Shahriar Eftekharzadeh – Bechtel, *Feasibility of Seawater Cooling Towers for Large-Scale Petrochemical Development*, Cooling Technology Institute Journal, Summer 2003, Vol. 24 No. 2, pp. 50-64. This paper is included as **Attachment C** to this report.

turbine drives the electric generator. The surface condenser is a heat exchanger. Low pressure steam condensing on the outside surface of the heat exchanger tubes as a result of cooling water flowing through the tubes. EPA notes that no problems specific to the retrofit have been encountered operating condensers originally designed for OTC in a closed-cycle system.[19] However, the wet tower retrofit cost estimate of $40 million (each) for HBSG Units 1&2 and Units 3&4 assumes that the surface condenser internals would be replaced to handle the higher hydraulic pressure of the plume-abated wet tower relative to the OTC system

3.4 Thermal Efficiency Penalty of Closed-Cycle Retrofit

The overall energy penalty of a conversion to closed-cycle cooling would consist of two components: 1) the thermal efficiency reduction of the cooling process, and 2) an increase in the power demand associated with cooling system pumps and fans. The power demand of the pumps and fans is often referred to as the "parasitic" load. The thermal efficiency penalty and parasitic load of closed-cycle cooling at HBGS are discussed in the following paragraphs.

The EPA examined the plant thermal efficiency reduction of converting from OTC to wet towers at the 346 MW Jeffries coal-fired plant in South Carolina.[20] The two Jeffries units came online in 1970 and were converted to closed-cycle wet cooling in 1985. A detailed study of the efficiency penalty associated with the conversion was conducted.[21] The annual average thermal efficiency reduction was determined to be 0.16 percent, with a peak hot day penalty of 0.97 percent.

The parasitic loads of fans and pumps associated with the closed-cycle cooling system are also components of the overall energy penalty of a conversion. The EPA has determined that there is essentially no difference in the pump power required for an OTC or conventional wet tower configuration.[22] This presumes that the cooling tower pump power requirements are offset by the elimination of the friction losses in the pipe drawing OTC water from the ocean to the plant. A plume-abated tower has higher pump head requirements than a conventional wet tower and would have a slightly higher parasitic power demand than a comparable once-through system in most cases. However, the wet tower system evaluated in this report for the HBGS circulates considerably less water, 190,000 gpm per unit versus 253,000 gpm per unit with the existing OTC system. This lower flow would reduce pump power requirements and would partially offset the higher hydraulic pressure of the closed-cycle circulating water system.

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[19] U.S. EPA, *Technical Development Document (TDD) for the Proposed Section 316(b) Phase II Existing Facilities Rule*, April 2002, Chapter 4.
[20] Ibid. p. 4-2.
[21] Ibid. p.5-34.
[22] U.S. EPA, *Technical Development Document for the Proposed Section 316(b) Phase I Existing Facilities Rule*, November 2001, p. 3-27.

The EPA estimated a generic parasitic wet tower fan power demand equivalent to a 0.73 percent energy penalty.[23] The total conventional wet tower annual energy penalty relative to OTC, summing the thermal efficiency penalty and fan + pump parasitic power demand, is approximately 0.9 percent. Assuming an overall efficiency penalty of 1.0 percent is a reasonable estimate for a plume-abatement tower, given the slightly higher pump power requirements for a plume-abatement tower.

3.5 Economic Impact of Closed-Cycle Cooling at HBGS

The installed wet tower capital cost of $40 million per unit would typically be amortized over 20 years. Assuming an interest rate of 7 percent, the annual capital recovery cost would be approximately $3 million per year per unit. The energy demand of the cooling tower(s) fans and pump requirements would consume about one percent of plant power generation above the demand of the OTC system. Assuming HBGS operates at 50 percent of capacity on an average annual basis, each unit will produce approximately 2 million MW-hr/yr of electricity. For the purposes of calculation the average price of wholesale power is assumed to be $70/MW-hr.[24] Therefore each unit would generate approximately $140 million per year in revenue. The capital cost of the cooling tower, amortized at $3 million per year, represents about 2 percent of annual revenue.

The one percent of unit power output that is consumed by cooling tower fan and pump energy demand equates to $1.4 million per year in lost income (20,000 MW-hr × $70/MW-hr). Reclaimed water would cost approximately $1.4 million per year per unit at a 50 percent capacity factor. The amortized cost of the reclaimed water pipeline would be $1.2 million per year in total, or $0.6 million per year per unit. The total cost impact of the closed-cycle cooling using reclaimed water from the LBWRP would be approximately $6.4 million per year per unit. The $6.4 million per year per unit cost for closed-cycle reclaimed water cooling represents approximately 5 percent of gross revenue. Use of seawater as the cooling medium would eliminate $2 million per year in reclaimed water expenses, reducing annual closed-cycle cooling system costs to approximately $4.4 million per year. The $4.4 million per year per unit cost for closed-cycle seawater cooling is approximately 3 percent of gross revenue. The financial impact would be lower in either case if HBGS operates at an annual capacity higher than 50 percent.

It is important to note that the HBGS is competing against newer plants that incorporate either reclaimed water or dry cooling. Use of reclaimed water in cooling towers at HBGS should be viewed as an appropriate "leveling of the economic playing field," not an economic burden that unfairly penalizes HBGS.

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[23] Ibid. p. 5-33.

[24] The average wholesale power price in Southern California (SP-15) in 2005 was approximately $70/MW-hr ($0.07/kw-hr) [reference: Energy News Data – Western Price Survey, 2005 weekly archives: http://www.newsdata.com/wps/archives.html]

3.6 Review of Actual Closed-Cycle Retrofits

Closed-cycle retrofits have been performed at several U.S. plants, as summarized in Table 1.

Table 1. Cost of Closed-Cycle Retrofits at Selected U.S. Sites

Site	MW	Flowrate (gpm)	Cost of Retrofit ($MM)	Cost of Retrofit ($/kw)
Palisades Nuclear	800	410,000	55.9	70
Pittsburg Unit 7	751	352,000	34.4	46
Yates Units 1-5	550	460,000	87.0[a]	158
Canadys Station	490		Not currently available[b]	
Jeffries Station	346		Not currently available[b]	

a) The Yates cooling tower is designed to achieve a 6 °F approach temperature. Original estimate $75 million. Revised $87 million cost includes wetland remediation, remediation of old asbestos landfill where towers were to be constructed, and reinforcement of concrete cooling water conduits.
b) The U.S. Army Corps of Engineers (COE) paid for the cooling tower retrofit. COE diversion of riverwater was the reason that the retrofit needed to be carried out.

Where accurate information is available on hook-up times, specifically at the Canadys Station and Jefferies Station sites, the closed-cycle system hook-up was completed within the scheduled annual maintenance outage period. The site-specific retrofit issues at each of the five sites listed in Table 1 are summarized in Table 2.

Table 2. Site Specific Issues Associated with Utility Boiler Closed-Cycle Retrofits

Site	Issues
Pittsburg Unit 7	Cooling towers replaced spray canal system. Towers constructed on narrow strip of land between canals, no modifications to condenser. Hookup time not reported.
Yates Units 1-5	Back-to-back 2x20 cell cooling tower. 1,050 feet long, 92 feet wide, 60 feet tall. Design approach is 6 °F. Cooling tower return pipes discharge into existing intake tunnels. Circulating pumps replaced with units capable of overcoming head loss in cooling tower. Condenser water boxes reinforced to withstand higher system hydraulic pressure. Existing discharge tunnels blocked. New concrete pipes connect to discharge tunnels and transport warm water to cooling tower.
Canadys Station	Distance from condensers to towers ranges from 650 to 1,700 feet. No modifications to condensers. Hookup completed in 4 weeks.
Jefferies Station	Distance from condensers to wet towers is 1,700 feet. No modifications to condensers. Two small booster pumps added. Hookup completed in 1 week.

3.7 Duration of Outage for Closed-Cycle Retrofit

Much of the work related to a closed-cycle retrofit can be carried out while the power generation units are online. Hook-up of the cooling tower requires an outage. Table 2 includes available information on the duration of the hook-up outage necessary to bring the closed-cycle cooling system online. The duration of the two retrofits for which detailed information is available, Canadys and Jefferies Station, is four weeks or less. The Yates Unit 1-5 conversion was accomplished without any additional outage time for the retrofit. However, the retrofit was apparently carried out during a time of low power demand when Units 1-5 can be offline for extended periods without impacting the dispatch schedule of the plant.[25]

It is unlikely the outage necessary for hook-up of the wet towers would have any impact on the operation of the HBSG units if the hook-up is carried out in a low demand period when the unit(s) is typically off-line.

3.8 Case Study: Closed-Cycle Cooling Retrofit at 1,600 MW Brayton Point Station

USGenNE is the owner of the 1,600 MW Brayton Point Station coal- and oil-fired power plant in Massachusetts. The company submitted a NPDES permit application in November 2001 that included an evaluation of retrofitting the plant from OTC to closed-cycle cooling.[26] The EPA NPDES permit issued to Brayton Point Station in October 2003 requires that the closed-cycle cooling conversion take place.[27]

The introductory paragraph in the closed-cycle cooling evaluation included in the Brayton Point NPDES application is instructive as it summarizes the major feasibility issues raised by most/all OTC plant owners facing regulatory pressure to convert to closed-cycle cooling. Regarding the challenges posed by such a retrofit, the Brayton Point application states:

Retrofitting conventional closed cycle cooling systems is a difficult engineering, design, scheduling, and construction effort due to its incompatibility with the original station design. The complexity of such a retrofit project is due to:

1. *The permanence of existing site features and structures;*
2. *The fundamental technical differences and incompatibilities between conventional closed-cycle cooling systems and the existing Brayton Point once-through cooling systems and condensers such as, the Station's condensers having a maximum design temperature of approximately 25 psig and a conventional closed-cycle condenser having a design pressure of 90 psig;*
3. *The difficult canal construction work that would be necessary to accommodate the plant operational requirements;*
4. *The installation of new, underground large diameter piping runs to the cooling towers;*

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[25] EPA Region 1, memorandum on conversion of Yates Plant Units 1-5 to closed-cycle cooling, January 2003

[26] USGenNE, Brayton Point Station – Evaluation of (Cooling) Technologies & Operating Practices, November 2001.

[27] EPA – New England, Brayton Point Station - Authorization to Discharge Under NPDES, NPDES Permit No. MA 0003654, October 2003. p. 3.3-1.

5. *The very limited open space available at Brayton Point as well as the topography in the vicinity of the area proposed for siting these towers makes their construction access and flow of job site erection materials complex, difficult, and extremely costly.*

EPA's decision to require Brayton Point to convert to closed-cycle cooling makes clear that the EPA does not view the technical challenges or economic impact at existing boiler plants to preclude converting to closed-cycle cooling. EPA also examined the question of closed-cycle retrofit outage times in its July 2002 Brayton Point Station NPDES determination.[28] The EPA essentially determined that the permittee was padding the estimated outage duration in an attempt to drive up the cost of thc closed-cycle retrofit. As stated in NPDES determination for the 1,600 MW coal- and oil-fired power station:

The permittee determined that an eight-month outage would be required for installing unit specific closed-cycle cooling towers for Units 1, 2 and 3, and a three-month outage would be required for installing such a tower on Unit 4. SAIC (EPA contractor) evaluated the permittee's construction outage estimates and, on the basis of a conservative analysis, concluded that they appear excessive. SAIC determined that the principal reason for the relatively lengthy construction outages estimated by the permittee is the permittee's "decision to install an entirely new set of pumping stations for the recirculation pumps for Units 1, 2 and 3 in a manner that interferes with the current once-through operation." According to SAIC, "this decision is based in part on the conclusion that the current pumps, piping and condenser may not be capable of handling the additional hydraulic pressure that would occur with the system if the condenser outlet were to be simply re-routed to the top of the new cooling tower.

In evaluating the permittee's approach, SAIC accepted the permitttee's concerns about piping and condenser pressure as valid. In addition, it reviewed four case studies involving large power plants that converted from once-through to cooling with closed-cycle mechanical draft cooling towers (one plant uses the towers in a helper mode). The conversions in these case studies were undertaken with either no outages or far shorter outages than those estimated by the permittee, . . . As SAIC explained, these other plants have "mostly been able to incorporate the existing pumps and pump stations, the existing condensers and much of the existing piping into the closed cycle systems." All but one of the four case study facilities were able to retain the existing once-through cooling water pumps and pumphouses and incorporate them into the wet cooling tower recirculation system, while the remaining facility kept the downtime "brief by installing a separate new pumphouse and piping in a manner that did not interfere with the existing system while under construction." As a result, this facility only required downtime to "disconnect the existing once-through cooling water pipes and reconnect the new cooling water system pipes." SAIC concluded that is likely that either approach would be feasible for Units 1, 2, and 3.

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[28] EPA – New England, Clean Water Act NPDES Permitting Determinations for Thermal Discharge and Cooling Water Intake from the Brayton Point Station in Somerset, MA, NPDES Permit No. MA 0003654, July 22, 2002. p. 4-77.

3.9 Air Emissions Impacts Imposed by Closed-Cycle Cooling System

Approximately 1 percent, or 4 MW, of the 430 MW capacity of each unit would be dedicated to the wet towers to meet additional wet tower pumping and fan energy requirements beyond current OTC pump power requirements. The plantwide total additional power demand would be 8 MW. If the replacement power for this 8 MW is generated by a combined-cycle plant, the annual NO_x and PM_{10} emissions associated with this replacement power would be a maximum of 1.5 tons/year and 0.7 tons/year, respectively, assuming a 50 percent annual capacity factor at HBGS.[29,30]

Advanced "drift" eliminators are incorporated into wet cooling towers to minimize this water droplet carryover. Some of this drift becomes PM_{10} as the aerosol droplets evaporate and leave behind a solid residue. Cooling towers using recycled water account for only a small amount of overall power plant PM_{10} emissions.[31] The primary source of PM_{10} is the combustion stacks. As noted, seawater is a potential wet tower cooling medium at HBGS if sufficient reclaimed water is not available. An industry survey of operators of seawater cooling towers notes these operators have not reported any problems associated with salt drift at their facilities.[32]

HBGS is located in the South Coast Air Quality Management District (SCAQMD). Power plant cooling towers are exempt from SCAQMD permit requirements. SCAQMD Rule 219 – "*Equipment Not Requiring a Written Permit Pursuant to Regulation II*" - states in section (d)(3) that written permits are not required for:

> *Water cooling towers and water cooling ponds not used for evaporative cooling of process water or not used for evaporative cooling of water from barometric jets or from barometric condensers and in which no chromium compounds are contained.*

The term "process water" has historically been interpreted by the SCAQMD to mean water originating from an onsite industrial process. Under current SCAQMD regulation cooling towers at HBGS using either reclaimed water or seawater would not require an air permit.

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[29] CARB, Guidance for the Permitting of Electric Generation Technologies, Stationary Source Division, July 2002, p. 9 (NO_x emission factor = 0.07 lb/M-hr combined-cycle plants)

[30] San Diego County Air Pollution Control District (APCD), Otay Mesa Power Project (air-cooled), Authority To Construct 973881, 18 lb/hr particulate without duct firing (510 MW output), equals ~ 0.04 lb/MW-hr.

[31] U.S. DOE, Final EIS - Imperial-Mexicali 230 kV Transmission Lines, December 2005. Table G-1, Power Plant Emissions, p. G-4.

[32] Dr. Shahriar Eftekharzadeh – Bechtel, *Feasibility of Seawater Cooling Towers for Large-Scale Petrochemical Development*, Cooling Technology Institute Journal, Summer 2003, Vol. 24 No. 2, pp. 50-64. Operators of seawater cooling towers have not reported any problems associated with salt drift at their facilities. Site inspections of two long-time saltwater cooling tower installations did not exhibit any visible signs of salts fallout.

As noted, the wet towers would be equipped with plume abatement technology to minimize visible vapor plumes.

3.10 Is OTC System Likely to Be Phased-Out in the Near Future With or Without the Desalination Plant?

Units 3&4 were upgraded in 2003. The cost of this retooling project was $130 million.[33] It is unlikely that AES or any future owner would voluntarily convert the cooling system to closed-cycle prior to a mandated OTC phase-out date without: 1) a regulatory requirement such as 316(b) requiring such an action, 2) a lawsuit forcing the a conversion, or 3) replacement with a combined-cycle gas turbine plant for economic reasons. HBSG is unique along the coast in that the owner simply upgraded an existing OTC steam boiler plant in 2003 instead of replacing the plant with a combined-cycle facility.

However, HBSG will not be able to compete on an efficiency basis with the new combined-cycle plants that are gradually replacing aging coastal boiler plants. Therefore it is quite possible that AES is weighing the near- to mid-term replacement of HBSG's boilers with a combined-cycle plant. The cost of replacing the existing boilers with the same capacity of combined-cycle plant would be $400 to $500 million. The $130 million cost of the Units 3&4 retooling project is significant but not so significant that it would necessarily impede AES from moving forward with a combined-cycle replacement project.

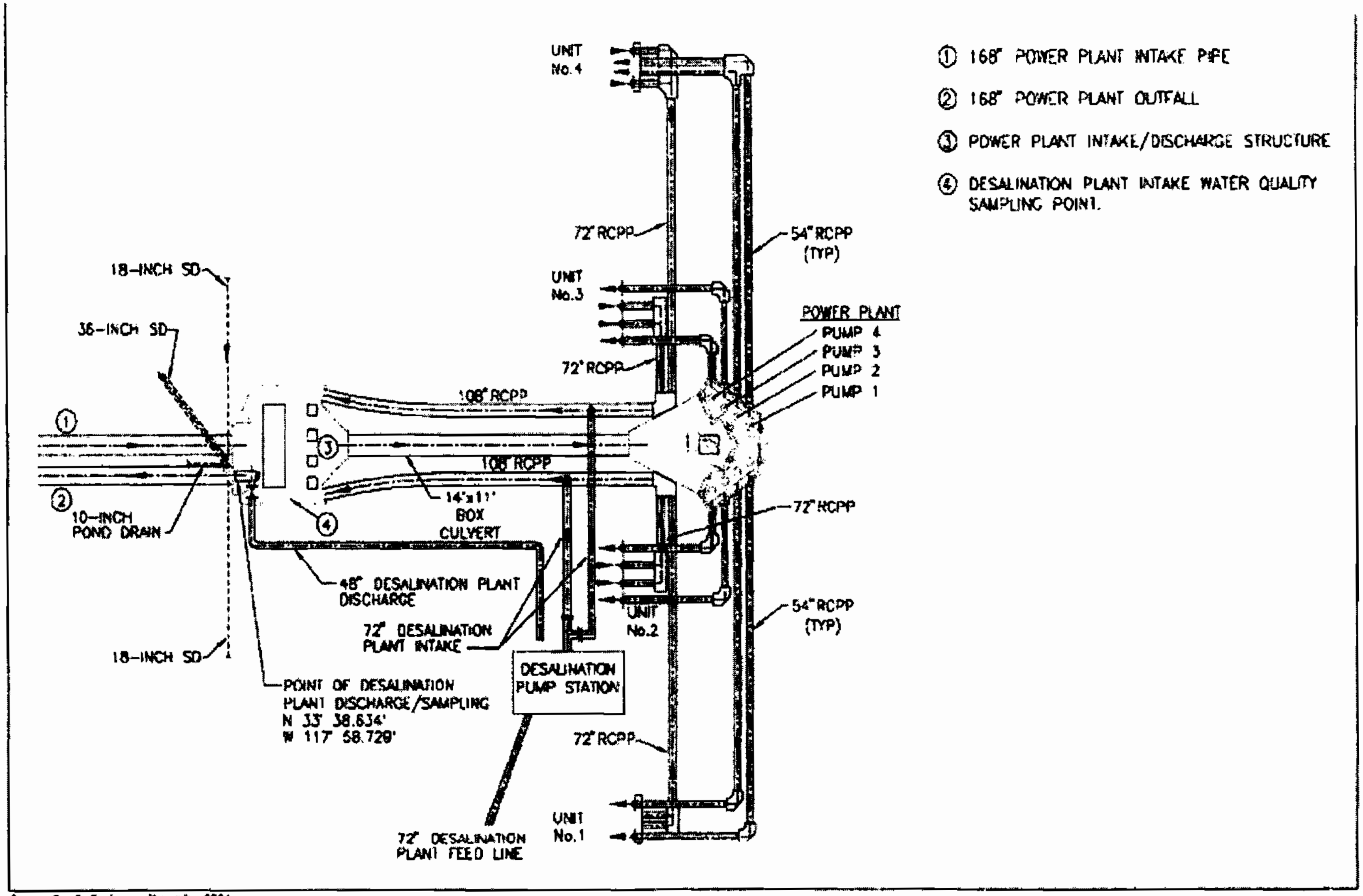
The principal problem posed by the proposed desalination plant is that it would occupy the only land on the HBGS site large enough to accommodate a replacement combined-cycle plant. The combined capacity of the HBGS is 860 MW. A combined-cycle plant of similar capacity, the 880 MW Delta Energy Center has been operational near Antioch, California since 2003. This project consists of three utility-scale gas turbines, three steam turbines, and one 12-cell wet cooling tower using reclaimed water. An aerial photo of the Delta Energy Center is provided in **Figure 5**. The 880 MW Delta Energy Center measures 550 feet by 900 feet without including the electrical switch yard. There is adequate space to construct a combined-cycle power plant of this size in the HBSG decommissioned fuel storage area and adjacent to the existing HBGS electrical switchyard. However, there will not be adequate space if the proposed desalination facility is constructed in the same decommissioned fuel storage area.

[33] California Energy Commission, *Huntington Beach Generating Station Retool Project – Application For Certification 00-AFC-13*, Amended Presiding Member's Preliminary Decision, April 2001, p. 15.

Figure 5. 880 MW Combined-Cycle Delta Energy Center (Antioch, CA)

Power plant dimensions: 550' width by 900' length (not including electrical switchyard)

Figure 2. Location of Desalination Piping Interconnections with Existing OTC System



Source: Carollo Engineers, November 2004.

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SEAWATER DESALINATION PROJECT AT HUNTINGTON BEACH

Desalination Facility/HBGS Cooling Water Connection

Exhibit 3-17

Figure 3. HBGS Potential Cooling Tower Locations that Avoid Power Plant and Desalination Structures

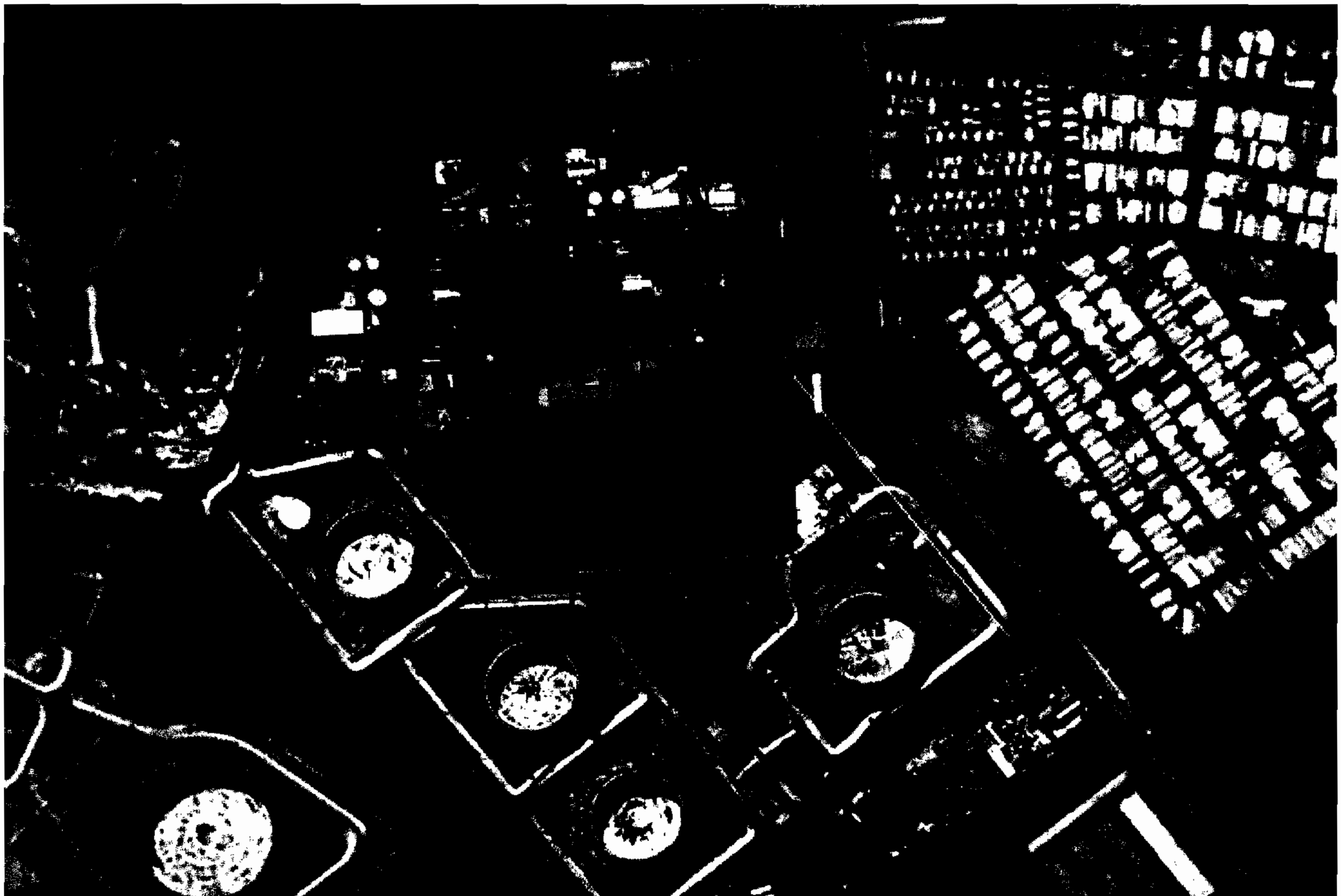
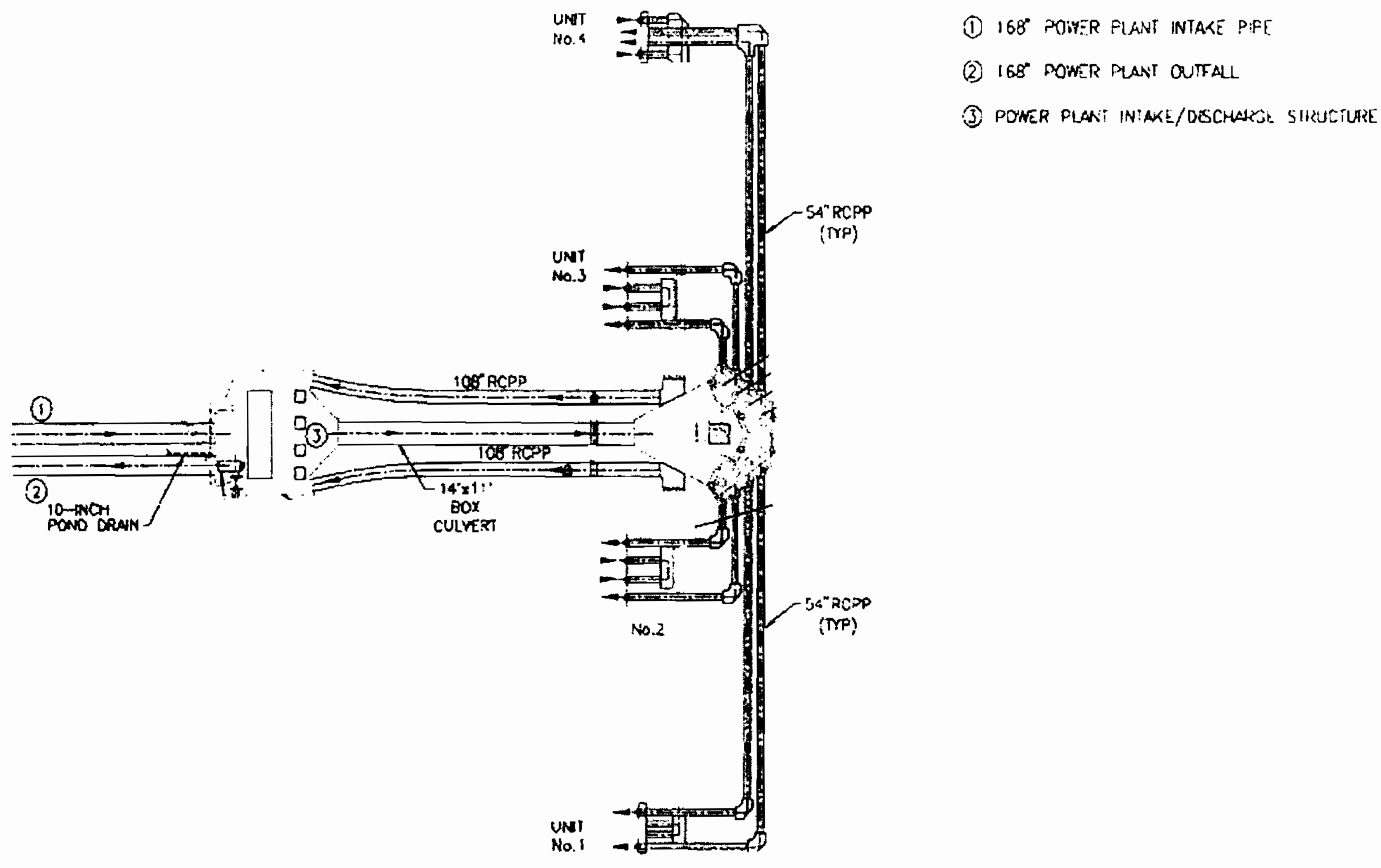


Figure 4. Potential Reconfiguration of Existing OTC Piping for Use with Cooling Towers



Source: Carollo Engineers, November 2004.

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HBGS Cooling Water